Energy Choice Matters

May 27, 2008

WGES Protests Rate Mitigation for New Type II Customers

The Maryland PSC's decision to mitigate SOS prices for new Type II customers may contravene the Commission's goal for energy conservation and discourage customers from actions to lower their high energy bills, Washington Gas Energy Services cautioned (9056).

While the Commission justified its three-month mitigation based on the assumption the additional time will allow new Type II customers to take actions to limit the impact of new quarterly prices (Matters, 5/23/08), WGES reasoned price mitigation may send the opposite signal. Commission action to limit price increases shows the PSC isn't serious about sending price signals that would prompt demand response and energy efficiency, WGES explained.

Rather, customers will continue to rely on the Commission to provide them with below-market prices, merely exacerbating the problem, WGES noted.

WGES also suggested that providing a subset of Type II customers with special discounts would be discriminatory in violation of Public Utility Companies Article §4-503(b), and would prompt complaints from non-mitigated Type II customers. Recovering the mitigation costs from all commercial customers, not just those receiving mitigation, would also prompt discrimination claims, WGES added.

Although the PSC justified suspending the Type II rates under Public Utility Companies Article §4-204(a) and §4-201, WGES argued that those two provisions apply to distribution rate cases, not SOS rates under the Restructuring Act which are governed by §7-510(c).

Public Utility Companies Article §4-204(a) and §4-201 also call for suspension of rates, subject to

... Continued Page 4

Industrials Raise Specter of CREZ Costs; PUCT Staff Outlines Risks from High-End Wind Scenarios

Integrating new wind generation will be more costly than was originally thought (Matters, 4/3/08), Jeffry Pollock, a consultant for the Texas Industrial Energy Consumers, argued in testimony regarding transmission planning for Competitive Renewable Energy Zones (CREZs).

Pollock noted the "overnight" cost for CREZ transmission is $2.95 billion (for 13,000 MW of wind capacity) to $6.38 billion (for nearly 18,000 MW). Absorbing CREZ-related investment would cause transmission rates to increase by between 41% and 90%, Pollock calculated.

With other new transmission needed to accommodate load growth and non-CREZ generation, transmission rates would increase 115% to 155%, Pollock estimated.

Accordingly, the CREZ transmission selection process should give priority to investments that integrate both wind and non-wind generation to provide maximum utilization and to minimize the rate impact, Pollock suggested.

Pollock argued that the GE ancillary services study failed to answer the question of the impacts that added wind development would have on the cost of ancillary services, because the study examined only one ancillary service: regulation. While the study claims that added wind power will lower the cost of other ancillary services and reduce production costs, the study did not quantify those assertions, Pollock observed.

GE failed to recognize that wind energy displacing primarily combined cycle generation and some coal generation from the energy market would increase costs, Pollock testified.

... Continued Page 4

AReM Opposes Changes to ESP Load Forecasting

Proposals to review load forecasting of Electric Service Providers during Phase I of the California PUC's investigation into local resource adequacy (RA) are untimely and inappropriate because they are contested issues that cannot be resolved quickly, the Alliance for Retail Energy Markets argued in reply comments (R.08-01-025).

Pacific Gas & Electric had suggested that the PUC needed to adopt a "current customer" approach to determining ESPs' load forecasts because PG&E alleged some ESPs have under-forecast, allowing them to avoid local RA requirements and defer system RA procurement from the year-ahead to month-ahead timeframe.

Under the current customer approach, ESPs' projected load would be based on their expected future customers plus the full load of their current customers unless a current customer has provided a binding notice of intent to discontinue service. It would replace the current "best estimate" of future load mechanism, though PG&E argued its proposal would indeed be the best estimate and is thus consistent with the current rules.

But AReM countered that the, "proponents for 'change' wish to cast aside the current RA processes for load forecasting established in 2004 and 2005 without so much as a workshop to discuss them."

The PUC's Energy Division has confirmed that the current RA processes have succeeded and that load-serving entities have procured sufficient local and system RA capacity since the program's inception, AReM argued.

While AReM considers the under-forecasting issue as clearly outside the scope of the proceeding, PG&E pointed to the inclusion of load migration in the Phase I scooping memo as supporting consideration of its proposal.

AReM also noted that PG&E's current customer approach has already been rejected twice by the PUC, but the Division of Ratepayer Advocates contended the PUC should revisit the issue at a later time. DRA recommended that the issue of under-forecasting be discussed in Phase 2, with an emphasis on the conditions that must be in place before the "best estimates" method is replaced by an approach similar to PG&E's proposal.

The California Large Energy Consumers Association and the California Manufacturers and Technology Association strongly recommended deferring the issue to Phase 2 as well, since a thorough review of the problems with the current methodology and the benefits and drawbacks associated within various alternatives is needed.

D.C. OPC Suggests Third-Party to Administer DSM Programs

As the SOS provider for Washington, D.C., Pepco is not the proper party to implement demand side management (DSM) programs and technologies, the Office of the People's Counsel told the PSC (FC 1056).

OPC reminded the PSC that Pepco earns a volumetric profit on SOS sales, and still serves commodity supply to 90% of District customers overall, and 99% of residential customers. Pepco's profit from serving residential customers, OPC calculated, amounts to \$0.88/MWh. The profit from small commercial customers is \$1.17/MWh and the profit from larger commercial customers \$1.75/MWh.

Consequently, Pepco's business interest of maximizing profit is in direct conflict with goals of reducing energy consumption through efficiency and DSM programs, OPC argued.

Allowing Pepco to be the monopoly provider of distribution service and unregulated generation supply and DSM would harm the retail competitive environment, OPC added.

OPC favors having an independent entity administer DSM programs, similar to the Sustainable Energy Utility contemplated by the Clean and Affordable Energy Act of 2008 (Bill 17-492).

Pepco should be the entity charged with installing advanced metering infrastructure in the District, OPC suggested, if the smart meter pilot finds system-wide installation to be beneficial. Pepco hasn't justified the cost effectiveness of smart meters yet, OPC noted.

OPC cautioned against any move to dynamic rates inherent in extracting the benefits of smart meters. Pepco has noted that customer participation in DSM activities depend on whether dynamic pricing is the default rate or an option.

OPC, though, contrasted mandatory dynamic pricing to municipal opt-out aggregation. Pepco and the PSC have been reluctant to endorse opt-out aggregation because they view it as a form of slamming.

But OPC countered that "radically" changing the pricing of electric service to 100% of District customers, without giving them any choice whatsoever, would result in far more significant disruption to electric service as currently experienced than would opt-out aggregation.

TURN, CFC Ask for Rehearing on Climate Institute

The Utility Reform Network and Consumer Federation of California (CFC) petitioned for rehearing of the California PUC's decision to create and fund the California Institute for Climate Solutions, arguing that the PUC exceeded its statutory authority (R. 07-09-008).

The PUC's decision to charge IOU ratepayers $600 million to bankroll the independent institute (Matters, 4/14/08) fails to adequately describe or explain the underlying authority the Commission believes permitted it to levy the tax on a subgroup of ratepayers for benefits that extend far beyond the Commission's jurisdiction, TURN said.

The PUC, TURN insisted, overlooked perhaps the most fundamental questions - does the agency have the authority to divert ratepayer funds toward an institution whose charge could extend far beyond matters related to energy utility service, and can the agency create out of whole cloth an independent entity to administer those funds?

TURN cited a Legislative Counsel of California analysis which concluded the PUC did not receive the authority to create its own climate institute under AB 32 or SB 1368.

If AB 32 were read that broadly, California would be at risk of seeing similar initiatives from other state agencies not directed to take particular actions under the statute, TURN cautioned.

"For example, the state's chiropractic board could increase the fees charged to California-licensed chiropractors in order to fund a transportation initiative, perhaps justified in the name of addressing the greenhouse gas produced when chiropractic patients drive to their appointments," TURN reasoned.

The Air Resources Board is already performing the function contemplated by the PUC's climate institute, only with legislative approval and at all taxpayers' expense, CFC added.

The PUC's institute will only interfere with the Air Resources Board's legislative mandate to create greenhouse gas regulations that are "equitable," "minimize costs and maximize the total benefits to California," and "do not disproportionately impact low-income communities," CFC claimed.

"The Commission has created an additional cost, intended to achieve unspecified benefits, which the Air Resources Board will be unable to assess and control." CFC noted.

"The Commission has no authority to impose another tax for the same purposes," CFC contended.

"Access to utility service should not be conditioned on payment of a tax to support research into greenhouse gas emission control, at a time when California consumers are facing cutbacks in public services arising from California's budget crisis, and other significant financial crises arising out of a recessionary economy, high gas and food prices, and a mortgage meltdown," CFC insisted.

The PUC's jurisdictional ratemaking authority, "involves a balancing of the investor and the consumer interests," and does not include raising funds for a quasi-public enterprise, CFC observed.

Briefly:

FPL Won May 7 Conn. RFP

FPL Energy Power Marketing won the entire Last Resort Service load for Connecticut Light & Power for the July through September period, CL&P disclosed after the confidential period expired (06-01-08PH02).

Calif. PUC Asks for Briefs on Debt Equivalence

A California PUC ALJ asked for comments regarding the issue of using debt equivalence to evaluate merchant generation projects when utilities consider RFO responses (R. 06-02-013). The PUC prohibited utilities from using debt equivalence adders when comparing utility owned generation and IPP projects in D.07-12-052, but utilities have asked for the decision to be modified. Among the assumptions and questions the ALJ asked for a response to was how does a new rate-based utility owned project affect the rating agencies' credit analysis? For example, if a service area is resource-rich, and an IOU is procuring additional new utility owned generation, does that factor negatively in the rating agencies' analysis? Or do other ownership risks such as technological obsolescence or the potential for non-recovery if a project runs over-budget or underperforms factored into the credit analysis? Opening briefs are due June 20 with replies due July 18.

Michigan Power Agency Wants RSG Refund

The Michigan South Central Power Agency (MSCPA) filed a complaint at FERC against the Midwest ISO, requesting that the ISO refund $366,000 in Revenue Sufficiency Guarantee (RSG) charges from virtual transactions (EL08-63). The ISO does not oppose resettlement and refund of the charges, but thinks express Commission approval is necessary. The virtual transactions were the power agency's means of mitigating its inability to obtain carved-out treatment of its Grandfathered Agreement No. 266 due to the combination of the Midwest ISO's imposition of day-ahead scheduling requirements even for carved-out load served through seller's choice agreements, and its supplier's refusal to provide MSCPA with sufficient information to be able to comply with such scheduling requirements. MSCPA argues that a prior FERC order relived it and other parties to carved-out GFAs of any RSG costs.

WGES Protest ... *from 1*

refund, while the Commission investigates the proposed rates. In the case of the Type II rates, the Commission has already found them to be just and reasonable, WGES claimed.

WGES suggested that should the Commission deem rate mitigation necessary, it should follow the deferral process established in SB 1 (2006) and previously used for residential customers at Baltimore Gas & Electric and the Pepco utilities. Such plans would defer rate hikes and recover costs from only those customers enjoying the deferral. Plans could be mandatory, opt-in or opt-out, WGES explained.

CREZ Transmission ... *from 1*

Given the generation stack in ERCOT, if additional wind generation would displace combined cycle generation (which is on a relatively flat portion of the bid stack), it will have little or no effect on market prices, Pollock reasoned.

Pollock also cited the impact of additional wind generation on ERCOT's increased reliance on out-of-merit capacity and replacement reserve service purchases in the West Zone in March 2008, a period of exceptionally high wind generation.

Direct Energy is concerned that the reliability of the ERCOT West Zone is threatened by the rapid development of additional wind resources in West Texas. Such development has significantly outpaced generator outlet capacity in the West Zone of ERCOT, where a majority of Texas' wind generation is already located, Direct noted.

Any transmission built to deliver additional renewable resources into the ERCOT region of Texas should be staged in a manner that does not further undermine the current condition of the ERCOT West Zone, Direct urged.

Panhandle resources should only enter the ERCOT market after new transmission construction and upgrades are completed which resolve existing ERCOT West Zone transmission constraints, Direct explained.

Consequently, construction of generator outlet capacity in the Texas Panhandle should be delayed until adequate outlet capacity is constructed within the West Zone and from the West Zone to the North Zone and to the South Zone, Direct noted. Luminant suggested a similar staging process which would allow periodic reviews of costs and assumptions regarding generation development.

While wind development has the potential to provide significant benefits to customers in ERCOT and to the environment, ERCOT's transmission studies suggest there are risks to customers from adoption of a CREZ order establishing a high level of wind development, cautioned Jess Totten, Director of the PUCT's Competitive Markets Division.

Wind development may not materialize at a level to fully utilize the CREZ transmission facilities, Totten noted, adding that the cost and feasibility of controlling the ERCOT electrical network in high wind development scenarios with the same level of customer reliability that exists today are not known.

The level of wind development that occurs outside of the CREZ process may impact transmission congestion that CREZ wind projects experience and the market prices that prevail in the wholesale market, Totten explained, which will determine how much CREZ generation is ultimately built.

The licensing and construction of CREZ transmission facilities will take several years and if, as the licensing and construction period passes, conditions are not conducive to additional development of wind generation facilities in the CREZ areas, there is a risk that the wind developers will not install additional generation facilities at the levels for which transmission facilities are being built, Totten observed.

That could leave ERCOT customers paying for more transmission than is needed, Totten cautioned.

Failure of Congress to extend the production tax credit for wind, and price levels in the wholesale market that would not support added wind investment, could cause interest in CREZ generation development to decrease from expected levels.

Be Sure to Check Monday's Issue

Energy Choice Matters published an issue on Memorial Day, so if you are returning to the office, check your inbox to make sure you've read about:

• Mass. Utilities Report on Bad Debt Caused by Disconnect Moratoriums
• Several ESCOs Amenable to Residential Customer Schumer Box in New York
• REC Broker Asks for Rehearing on Nstar Green Billing
• ARM, TEAM Cite Concerns Over CenterPoint AMIN Plan
• MEA Sees EmPOWER Maryland Goals Achievable Without Smart Meters
• FERC Approves Demand Response for New York Reserves, Regulation
• TDUs Cite New SPP Members as Degrading MISO Western Markets Plan
• FERC Revokes MBRs for Two Traders